Energy Storage Study

MISO, Policy Studies

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1. Executive Summary

MISO is part of GO-15, an initiative with the largest power grid operators in the world to investigate fundamental issues of common interest to its members and develop joint action plans addressing improvements to power system reliability. As part of its involvement in GO15, MISO is leading the initiative on Working Group #7 to examine how factors such as renewable penetration, demand response, and electric vehicles play a role in the viability of large scale energy storage.

As more variable generation resources are added to the transmission grid, the system complexities increase with balancing generation and demand. Greater flexibility is required in order to maintain reliable service. In this circumstance, the role that grid-scale energy storage plays in system planning becomes important. Long-term energy storage is attractive because it can be used to shift electricity generated during low-demand periods for use during peak demand. Short-term energy storage also has potential value in providing a frequency-regulating resource and ramping capability to maintain system stability. MISO currently accommodates long-term storage resources in its markets in the form of pumped hydro storage (PHS). Short-term storage is accommodated as a Stored Energy Resource capable of supplying regulating reserves in the MISO Energy and Operating Reserve Markets.

To better understand the role of energy storage, MISO initiated the Energy Storage Study to model several hypotheses surrounding PHS, compressed air energy storage (CAES), and battery storage technologies. This study will explore the benefits that storage technologies could provide as well as the economic potential for storage technologies in the MISO region. Also, it will examine the grid-scale energy storage potential within the MISO footprint when large amounts of variable generation are added to the system.

Current state legislated renewable portfolio standards (RPS) within the MISO footprint will equate to an average requirement of approximately 10 percent of generated electricity by 2030 to come from renewable resources, primarily from wind (which requires an additional 4.5 GW of wind to the existing 19.8 GW). Typical wind patterns produce higher energy at times when electricity demand is low, while solar produces higher energy at times when demand is high. Wind and solar generation are also variable and have to be balanced with other resources in order to maintain system reliability.

Previously MISO conducted an energy storage study by MISO in 2011. Since that time, there have been several changes to the MISO system and modeling assumptions that have been incorporated in the current study. Several of these changes include unit retirements, retrofits and installments along with system footprint and membership changes. The impact of these changes is examined to provide a further analysis of the benefit large-scale storage technologies can provide in MISO.

The results of this study indicate that current conditions in the MISO footprint do not find large-scale investment in storage to be economical. However, in certain scenarios, the energy arbitrage potential exists with having coal units as the marginal unit during off-peak demand, and gas units as the marginal unit for peak demand. Furthermore, renewable penetration is found to have a positive impact on the energy arbitrage potential for storage because it helps bolster the amount of lower priced off-peak energy available for storage to utilize.

2. Introduction

In order to understand the potential for energy storage in the MISO footprint, we use the software tool Electric Generation Expansion Analysis System (EGEAS). EGEAS is a capacity expansion planning tool designed by EPRI (the Electric Power Research Institute) to find the optimum resource expansion plan. The EGEAS model identifies circumstances when adding energy storage resources to the MISO footprint would be economically justified. The primary benefit of using EGEAS is that it can identify the economic benefit from energy arbitrage along with any capacity benefits of the selected storage technologies. However, it has limitations for modeling energy storage technologies, particularly short-term storage such as batteries because the model does not capture any benefit from the ASM.

There are also other shortcomings to the EGEAS model with regard to storage benefits from energy arbitrage because the price data used may not have the granularity to capture optimal energy arbitrage economics. EGEAS also does not model the congestion from transmission constraints, which could show higher costs for energy during times when transmission limits prevent the dispatch of the least-cost resource. The EGEAS model is however useful for running a large number of scenarios in a short time in the form of reserve capacity expansion plans. These runs reveal when and under what conditions energy storage becomes economically viable.

The EGEAS model can be used with pre-existing data assembled for the MTEP 2015 planning process to compare model results in different scenarios with or without storage available as a resource. The scenarios include variations in fuel costs (natural gas prices), EPA regulation retirement impacts, carbon tax, and RPS mandate percentages. The EGEAS model indicates economic benefits from energy arbitrage storage in several cases and thus confirms a primary study objective by proving that economic benefit exists from energy storage in MISO.

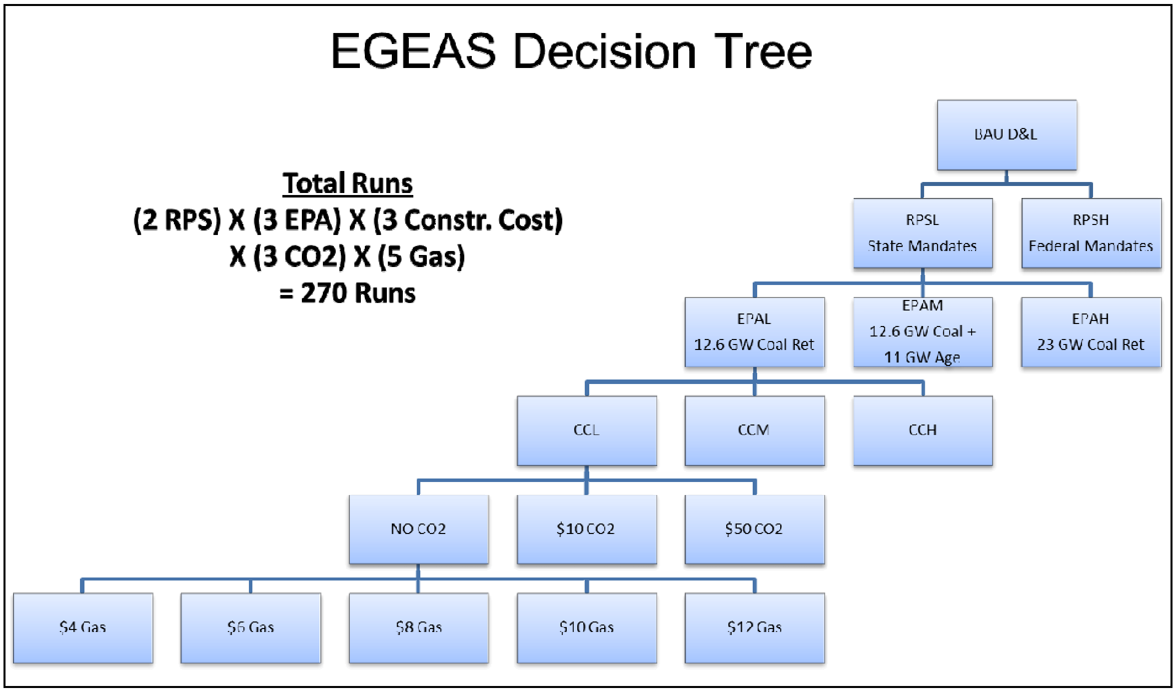
3. EGEAS Energy Storage Model Assumptions

For the Energy Storage Study, EGEAS models a 20-year capacity expansion starting in 2014 with each year broken into 12 segments for generation. Since MISO already uses the EGEAS model in MTEP studies, the Energy Storage Study is able to incorporate data from existing analysis. The MTEP studies have always included pumped hydro storage since MISO has roughly 2500 MW in use today. The MTEP 2015 analysis included CAES as a supply side alternative. The Energy Storage Study added battery storage to PHS and CAES. The key sensitivities explored in the study are gas prices, RPS levels, carbon tax, coal retirements and storage unit construction costs. For the Energy Storage Study, MISO staff used the EGEAS dynamic programming tool.

3.1 EGEAS Sensitivities

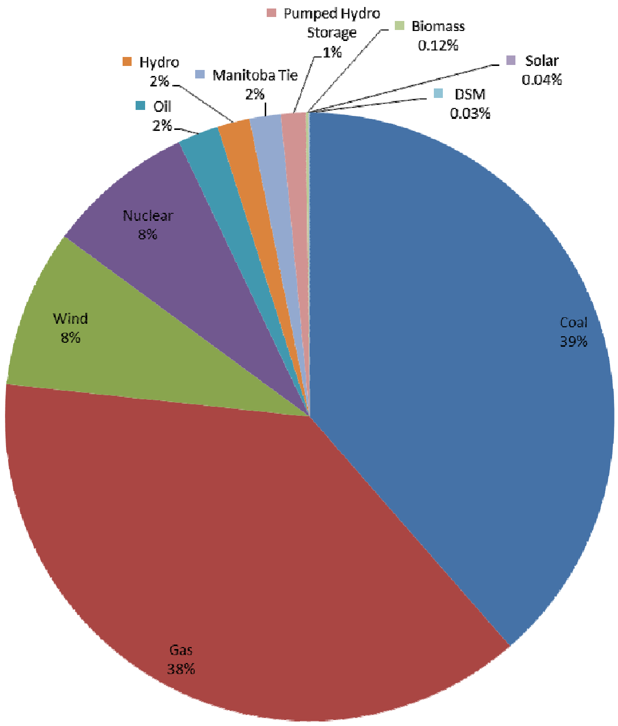
The following sensitivities are evaluated in the MISO Energy Storage Study:

- Natural gas (Henry Hub) starting year prices @ \$4, \$6, \$8, \$10 and \$12 / MMBTU
- Retirements (12.6 GW Coal, 12.6 GW Coal + 11 GW age related, 23 GW Coal)
- RPS (State Mandates – 10 % by 2030, MISO-wide mandates 30 % by 2030)
- Carbon tax (\$0, \$10, \$50 per ton)
- Overnight construction costs for storage units
  - Low: CAES \$957/kW, PHS \$4050/kW, Battery \$1914/kW
  - Mid: CAES \$1085/kW, PHS \$4590/kW, Battery \$2170/kW
  - High: CAES \$1276/kW, PHS \$5400/kW, Battery \$2552/kW



The study uses the 2014 installed capacity (by fuel category in MW) as the baseline for resource planning.

Resource Mix of MISO Footprint for 2014



Fuel Category	MW	Percentage
Coal	73,640	39%
Gas	72,724	38%
Wind	16,032	8%
Nuclear	14,953	8%
Oil	4,150	2%
Hydro	3,272	2%
Manitoba Tie	3,157	2%
Pumped Hydro Storage	2,518	1%
Biomass	224	0.12%
Solar	76	0.04%
DSM	66	0.03%
Total	190,812	

The economic base case assumption used for the Energy Storage Study is taken from the MTEP 2015 future scenario analysis. The scenario chosen is the planning advisory committee (PAC) Business As Usual scenario, which models the power system as it exists today with reference values and trends based on recent historical data and assume that existing standards for resource adequacy, renewable mandates, and environmental legislation remain unchanged.

The study period for the EGEAS analysis is 20 years from 2014. The EGEAS model also includes an extension period of 40 years to counteract any "end effects". The end effects are caused because asset-planning horizons exceed 5 years causing retirements, regulations and construction to taper off during the final study years. The demand and energy annual growth rate assumption is 0.80 percent. The starting value for demand is 125,748 MW and for energy 671,227 GWh. Inflation is assumed to be 2.5% per annum and affects economic costs and fuel prices with the exception of natural gas. Natural Gas inflation is calculated from the Bentek forecast. Energy efficiency and demand response are modeled based on state requirements over the study period which total to 1545 MW.

Plant revenue assumptions are based on low medium and high overnight construction costs and are calculated from capital and production costs over the twenty-year period. Overnight construction costs for CAES are about 55.5 percent of the values for PHS reflecting the higher infrastructure cost to build pumped hydro. Battery overnight costs are approximately double CAES in $/kW terms. These cost assumptions are extremely important in the EGEAS energy study analysis since the model chooses new plant investment based on costs.

The equivalent "mid" overnight construction costs assumed for CT and CC units are $690/kW and $1,045/kW respectively. The CT and CC costs were not varied when the energy storage costs were raised or lowered (low and high values) because the estimates are more stable – using the latest EIA construction cost estimates. The unit capacities input into EGEAS for PHS, CAES, and Battery are equivalent at 1200 MW. Using the same capacity values for each of the storage types allows the resources to have equal consideration for capacity selection based on their costs. In contrast, having different capacity sizes among the storage resources could have a more costly resource selected because its size will meet the reserve shortage needs over a smaller but potentially more economical unit.

Construction lead-time for PHS is the longest at 5 years, battery storage is given a 2-year lead-time and CAES is estimated at 3 years. The CAES heat rate is assumed to be 4000 Btu/kWh, which is just over half the Btu rate for an equivalent combined cycle or CT generating plant. This is because the compressed air in the CAES plant improves generation efficiency during the discharge cycle, although there are electricity costs incurred during charging.

3.2 Electric Vehicles

For the Energy Storage Study, electric vehicle demand and growth is taken into consideration. The growth projection is based on the Energy Information Administration (EIA) Annual Energy Outlook (AEO) of yearly sales for electric and plug-in electric hybrid cars and light trucks. The historical average percentage of EVs in MISO is 4.24% out of the total EVs in the U.S, and this percentage is applied to the growth projection to calculate the number of EVs in MISO over the study period.

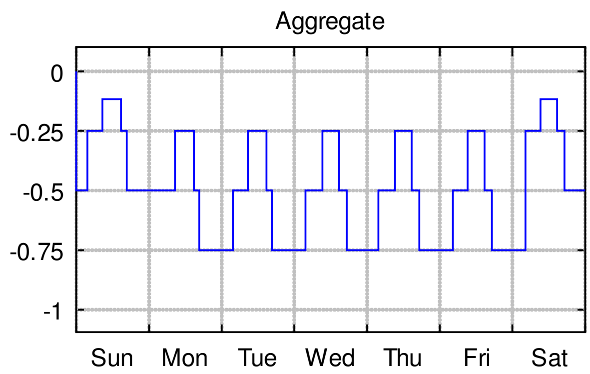
EV's in MISO footprint						
	2006	2007	2008	2009	2010	2011
U.S. EVs	53,507	55,706	56,856	56,407	57,451	66,614
MISO EVs	2,263	2,225	2,421	2,728	2,339	2,686
% EV's in MISO	4.23%	3.99%	4.26%	4.84%	4.07%	4.03%

For this study only AC Level 1 and Level 2 charging were taken into consideration. Charging rate capabilities are provided below for Level 1 and Level 2 electric vehicle supply equipment.[1]

Charging Rate Capabilities						
	Current Type	Amperage (amps)	Voltage (V)	Kilowatts (kW)	Charging Time *(for fully depleted battery)*	Primary Use
Level 1	AC	Up to 15 amps	120V	Up to 1.8 kW	6 to 20 hours	Residential charging
Level 2	AC	Up to 80 amps	240V	Up to 19.2 kW	3 to 8 hours	Residential and public charging

According to the Department Of Energy, most residential Level 2 supply equipment only has a maximum charging rate of 30 amperes and 7.2 kW. For the Energy Storage Study, Level 2 charging at 3.3 kW per EV is used and applied to each vehicle over a weekly charging profile. The weekly EV charging profile is reflective of the changes that occur over the course of the day with increasing battery charging in the evening and a reduction in charging by the early morning. Additionally, the basis of this profile comes from a DOE sponsored project called "The EV Project."[2] This project provided electric vehicle supply equipment to EV drivers at no cost in exchange for collecting data on the vehicle and the equipment, including energy used and time and duration of charger use.

Weekly EV Charging Profile



[1] See DOE Developing Infrastructure to Charge Plug-In Electric Vehicles.
[2] See "The EV Project" at http://www.theevproject.com/.

4. Results Summary for EGEAS

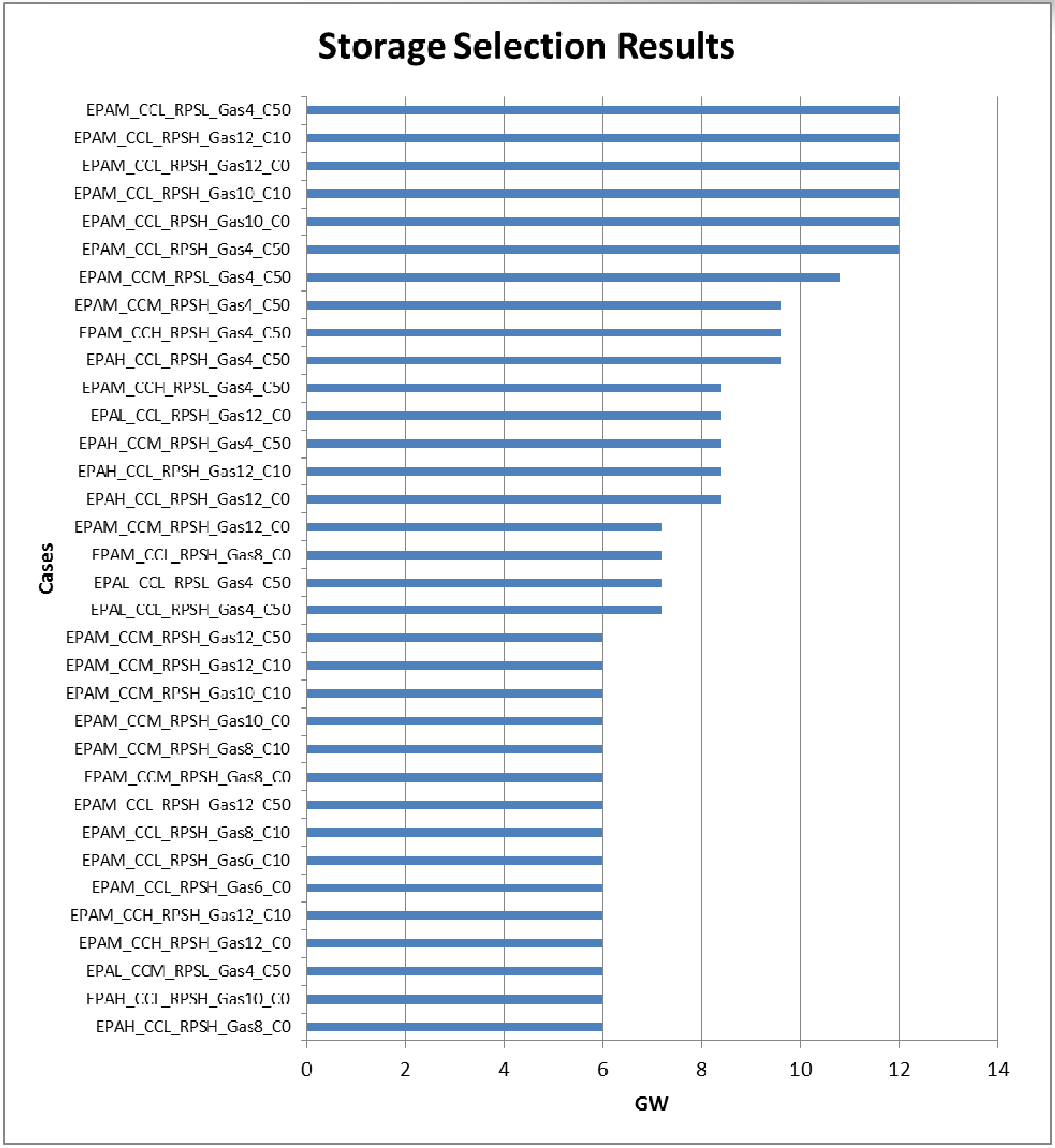
The EGEAS modeling results for the Energy Storage Study indicate that although there is overall opportunity for long-term storage resources in certain future scenarios, the existing MISO market and tariff conditions currently do not find large-scale investment in storage to be economical. This result is still consistent with what was found in the Energy Storage Study performed in 2011.

The EGEAS storage model has limitations that hide potential benefits from storage resources. In particular, because EGEAS did not model intraday ancillary services, any benefits for these services are ignored. While this constraint is clearly identified upfront in the analysis, it effectively precludes the model from identifying economic benefits from short-term or regulation only resources, such as batteries, flywheels, etc.

Where the EGEAS model did identify economic benefit from energy arbitrage, the benefit was restricted by several factors. The first is that the addition of the MISO southern region changes the resource mix of the system. The South footprint brings in a significant amount of gas units which increases the occurrence of gas units being the marginal units in off peak periods, thus reducing the potential for energy arbitrage. When the Energy Storage Study was first performed in 2011, the generation mix within the MISO footprint consisted primarily of coal units and there was a surplus of excess capacity available. This large amount of coal capacity meant that the off-peak demand as well as the peak demand would be satisfied by coal because high renewable penetration caused coal to be the marginal unit for peak load. Therefore, the energy arbitrage available at that time came from inexpensive coal units and more expensive coal units.

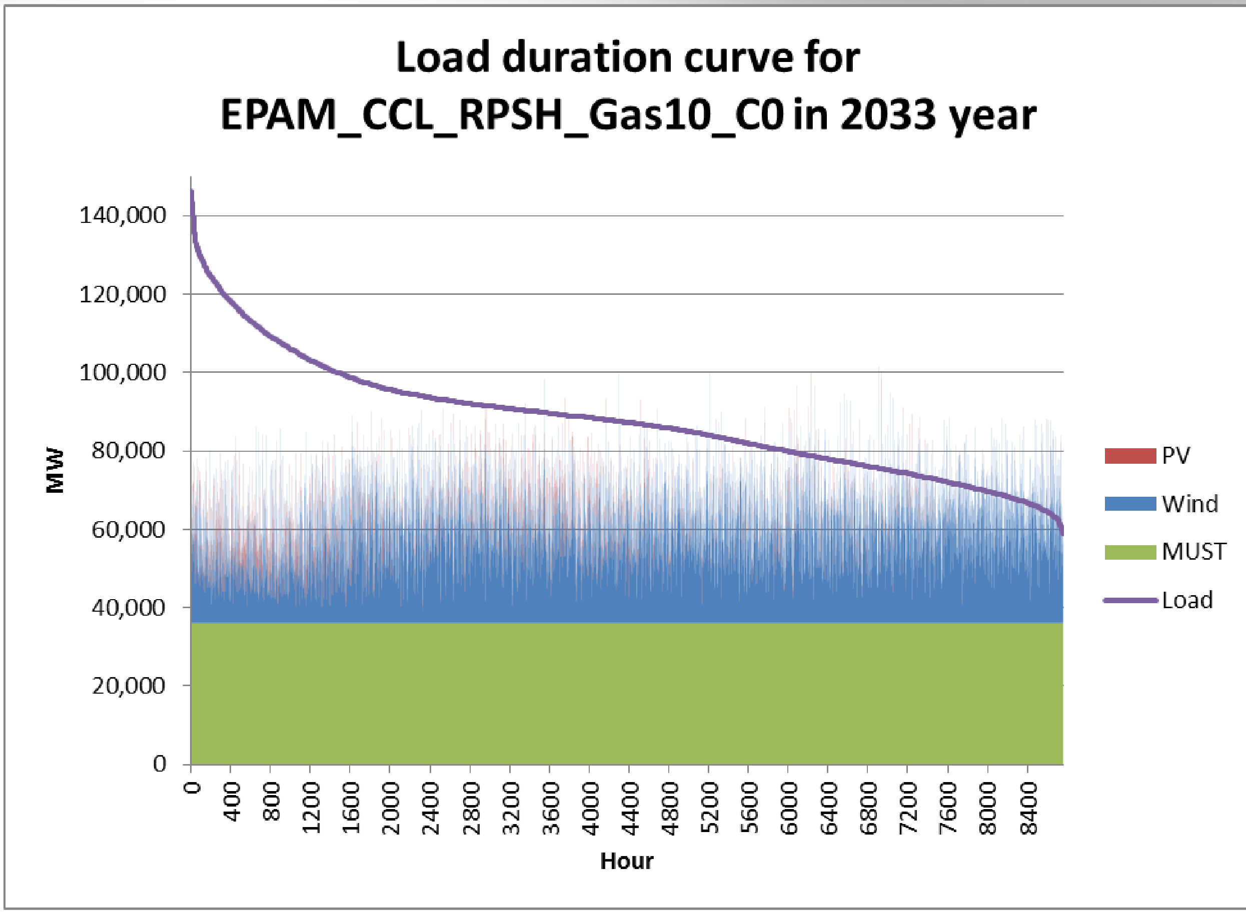
With the current MISO footprint, the energy arbitrage potential exists with having coal units as the marginal unit during off-peak demand, and gas units as the marginal unit for peak demand. The divergence of production costs between coal and gas units creates the potential for storage to charge at the low marginal price of coal and discharge at the high marginal price of gas. The study also showed that the potential for energy arbitrage was reduced when the production costs of coal and gas units were similar.

Renewable penetration was found to have a positive impact on the energy arbitrage potential for storage. The reason being is that the renewable energy helps bolster the amount of lower priced off-peak energy available for storage to utilize. If there is low renewable penetration, the amount of baseload generation and available renewable energy would be at or slightly higher than the minimum demand of the system. When this occurs, there is little room for storage to benefit from energy arbitrage because baseload generation is not able to set the marginal price for enough periods.



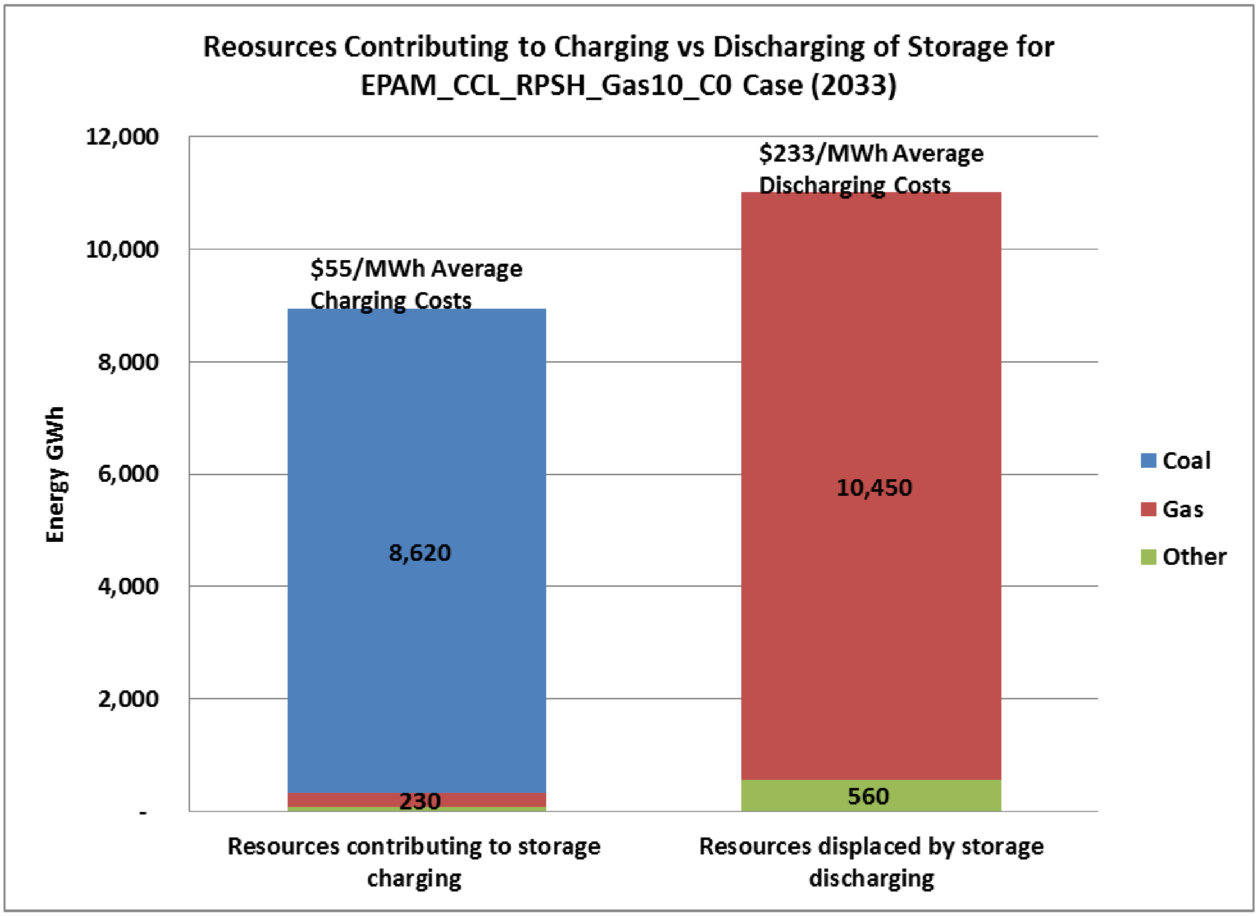
EPA = Generation Retirement (low, medium, high), CC = Construction Costs (low, medium, high), RPS = Renewable Penetration (low, high), Gas = Gas Price ($4, $6, $8, $10, $12), C = Carbon Costs ($0, $10, $50)

In the above chart, the cases where the most storage was selected are shown. The maximum amount of storage capacity added was 12 GW in the cases with medium EPA retirements, low construction costs, and high renewable penetration. Additionally, $10-$12 gas prices and $0-$10 carbon costs yielded the most storage selection on one spectrum, while $4 gas price and $50 carbon costs yielded just as much storage selection.



The chart above shows one of the cases where some of the highest amounts of storage were selected in the model. The sensitivities for this case are medium retirements, low construction cost, high renewable penetration, $10 gas, and no carbon cost. It shows the load duration and the amount of renewables and must run to meet the load in the final study year. In the min load periods, there are instances where the renewables and must run meet the load obligation or oversupply. This indicates an opportunity for storage to be utilized because of low energy prices and takes away the opportunity for gas units to be the marginal resource in both on and off peak periods. Off peak periods with must run and renewables as the marginal unit create the price differential needed to make storage selection ideal. When gas units set the marginal price in the peak periods, the storage units are dispatched and able to make use of energy arbitrage. The amount of must run shown reflects a percentage of the megawatt contributions from the first loading blocks of all units on the system that are designated as “must-run” accounting for the fact that not all must-run units are online at the same time due to seasonal or maintenance outages, etc.

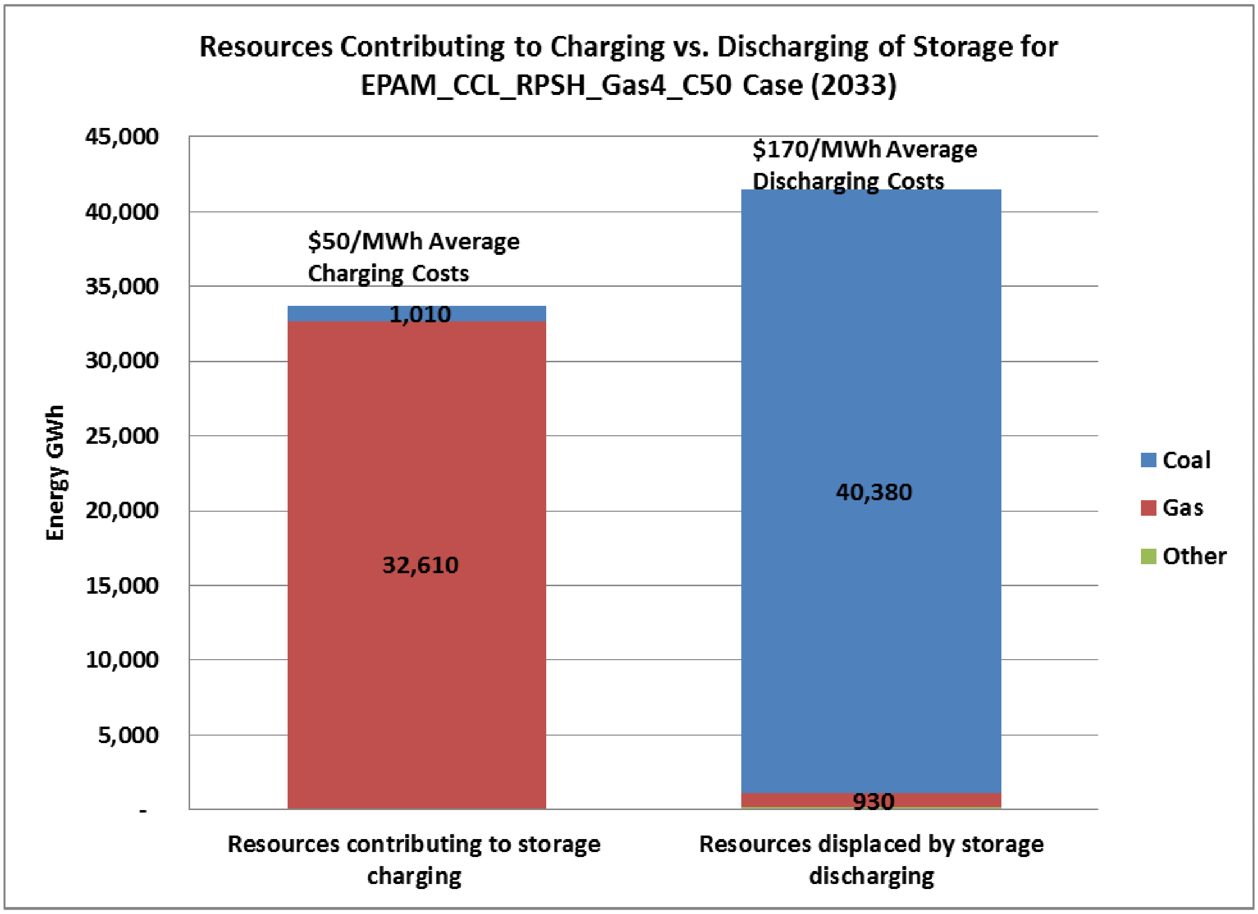
Retirements also play a key role in storage potential. The retirement sensitivity that resulted in the most storage additions was the medium retirement case with 12 GW of retirement from coal and the remaining 11 GW from age related retirements. The high retirement sensitivity, with 23 GW of retirement from coal, had the next largest amounts of storage added. According to these results, the retirement of existing resources benefits storage up to a certain extent. When 23 GW of retirement comes solely from coal, it negatively impacts the energy arbitrage potential because gas units become the marginal unit in the off peak more frequently. However when 12 GW of retirement comes from coal and the remaining 12 GW are age related retirements, it creates an opportunity for storage to displace those retired units, while minimizing the occurrence of gas units setting the marginal price in the off peak due to a lack of baseload generation.



The chart above shows which resource types contributed the most to storage charging and discharging and the average costs during those periods. The case shown is for medium retirements, low construction costs, high renewable penetration, $10 gas price and no carbon cost where 12 GW of storage was added to the system. Under this set of sensitivities, coal units contribute as the primary resources for storage charging at an average charging costs of $55/MWh, while gas units contribute primarily to storage discharging at $233/MWh.

With regards to capital cost, the most storage selection occurred in the cases with low capital costs for storage resources. This was expected though because lower capital costs mean that there is a smaller amount of energy savings required for storage to exceed its capital costs and provide economic value.

Carbon costs impact the system by reducing the storage potential when coal is the baseload resource and gas is the peaking resource. Under scenarios where gas prices remain low, high carbon costs make gas units ideal as baseload generation. Storage was found to run much more very frequently under this scenario, while its frequency of operation decreased as the gas price increased. Below is a chart of the medium retirements, low construction costs, high renewable penetration, $50 carbon cost, and $4 gas price case, with 12 GW of storage also added to the system.



The chart shows that most of the storage charging occurs with gas units as the marginal unit, while the coal units provide high energy costs for storage discharging. Additionally the average cost for charging is $50/MWh and discharging cost average $170/MWh. From this data, we see that a switch occurs with gas units becoming marginal units during off peak periods because the carbon costs have priced coal units at higher costs. Even though this case has a lower price spread between off peak and peak costs than the case with $10 gas and no carbon costs, it makes up for that lower price spread by having storage utilization for longer durations.

Multiple sensitivities were not created for demand response, energy efficiency, and electric vehicle amounts because their primary purpose was to be accounted in the model for accuracy. It was important to account for these inputs because they play a role in the future of the system through potential peak shaving. Peak shaving could however negatively impact storage because it reduces the energy arbitrage potential.

5. Conclusion

This study identified potential opportunities for energy storage to be viable. Those opportunities exist under various conditions with retirements, construction costs, renewables, gas prices, and carbon costs. With the addition of the MISO South footprint , more scenarios can provide new opportunities for energy storage because of the change in resource mix of the system. Additionally, CAES is the preferred storage resource selected when competing with battery and PHS, even though it has associated fuel costs and the other technologies do not. This is primarily because of its much lower construction costs and higher efficiency. However, this study only considers the energy arbitrage incentives along with planning reserve margin contributions and further analysis is needed to explore the other financial opportunities available for storage, such as the ASM that could provide key incentives for battery and other fast-response, shorter term technologies in the intra-hour periods.